Job Loss Analysis

ID No: 2000310 **Status:** Closed **Original Date:** 11/3/2010
Last Review Date: 7/10/2012

Organization: Global Manufacturing

SBU: Global Manufacturing Shared
BU: Refining
Work Type: Technical Process Engineering
Title (Work Activity): Troubleshooting Amine Column Foaming
Site/Region:

Personal Protective Equipment (PPE)	Selected	Comments
Proper PPE per your Refinery Guidelines	X	

Reviewers

Reviewers Name	Position	Date Approved
Jimmy Lam	Senior Process Engineer (RIC)	7/2/2012
Brandon Hughes	Process Engineer (SLC)	6/29/2012
Steven Mouton	Process Engineer (PAS)	6/29/2012

Development Team

Development Team Member Name	Primary Contact	Position
Bart Welch	CTN 938-4732	Amine and Sour Water BIN Leader
Amine BIN Team		Process Engineering and Amine Plant Operations (11)

Job Steps

No	Job Steps	Potential Hazard	Critical Actions

1	Ensure Amine Absorber or Regenerator Foaming (Instability) is adequately mitigated.	1. Amine tower foaming may result in the following downstream impacts: • Environmental Exceedance due to SRU upset or High H2S in Fuel Gas. • Carryover of large volume of liquid from Absorber into Fuel Gas System. • Carryover of large volume of liquid from Regenerator to SRU's resulting in unit shutdown and/or damage.	1A. Follow JLA steps listed below to diagnose and address abnormal behavior due to foaming before regulatory or downstream impacts occur. 1B. Ensure Amine Unit Operations Training and Procedures include the correct stabilizing actions (listed below) for Foaming.

2	Incorporate foaming related variables into routine process monitoring	1. Fouling or damage to column internals which is not identified in a timely manner may lead to premature flooding and loss of capacity. 2. Flooding / foaming symptoms are unnoticed by Process Engineering because daily averages typically used in Monitoring do not have enough resolution to catch sporadic upsets. 3. Signs of increasing contamination of the amine may be unnoticed until consequences are severe.	1. Monitor long term trends of Absorber and Regenerator dP's (e.g. 1 year of daily averages), look for steady increase or step change above historical baseline. 2. Monitor short term trends of Absorber and Regenerator dP's with a tight interval (e.g. a few weeks of ~10 min averages). 3A. Track antifoam usage and particulate and carbon filter change-out frequency. 3B. Routinely sample of carbon drum in&out to ensure carbon is changed out appropriately. 3C. Become familiar with appearance of amine (color, haze, particulates) during normal operation as a comparison to aid in troubleshooting upsets. 3D. Systems with a history of contamination issues should consider routine testing of TSS, oil, benchscale foam tests, and/or surface tension.
3	Identify symptoms	1. Problem not identified in a timely manner and/or problem mis-diagnosed.	1A. Primary symptoms of foaming are: • High pressure drop (dP) across internals • Erratic bottoms level, with the level initially dropping (level valve closes) as liquid stacks on trays or packing. • Erratic dP 1B. Additional symptoms which may or may not occur (depending on severity): • Carryover of liquid to overhead drums • Fluctuating emissions (H2S in Fuel Gas and/or SRU Tail Gas due to fluctuating acid gas rates) • Increased pressure or gas vent rate from Rich Amine Flash Drum • Erratic flow from Rich Amine Flash Drum to Regenerator (in control schemes where Regenerator Bottoms level controller adjusts this flow) • Temperature profile moving up Absorber

4	Determine if symptoms are caused by flooding or foaming	1. Despite similar symptoms, the mitigations for foaming and flooding are different and therefore a mis-diagnosis will delay resolving the problem.	1. Examine process data from upsets to classify. Foaming is caused by contamination and is erratic by nature, with episodes occurring over a range of tower conditions and rates. Flooding occurs when vapor and/or liquid rates in the tower exceed the capability of the internals; flooding is consistent and should repeat when the tower is returned to the same conditions where it previously occurred. • Flooding can only be addressed by reducing gas and/or liquid rates, or by cleaning/repair if flooding is occurring (below design rates) due to fouling or damage.
5	Verify issue is not caused by malfunctioning instrumentation {FYI – while it is good practice to check the instrumentation, more often the instruments are okay and the tower really is foaming rather than the other way around; the assumption of malfunctioning instrumentation is common because the signs of amine contamination are often subtle}	1. Problem not identified in a timely manner and/or problem mis-diagnosed.	1. Eliminate possible causes by trending flowmeters vs. valve positions and mass balancing flows (e.g. lean vs. rich) to identify inaccurate measurements. Involve Process Control if a controller appears to be improperly tuned. Possible instrumentation issues which may cause flooding-like symptoms are: • Too much steam to reboiler (e.g. due to flowmeter reading erroneously low) may flood Regenerator • Too much sour gas feed or Lean Amine flow (e.g. due to flowmeter reading erroneously low) may flood Absorber • Erratic reboiler steam flow (e.g. control valve sticking) can swing Regenerator • Rich Amine flow from Rich Amine Flash Drum to Regenerator is high or swinging • Malfunctioning level controller may swing bottoms level (but will not change column dP) • Large change in water makeup, reflux purge rate, or amine losses may create loss of level (but will not change column dP) • Swinging regenerator reflux rate (e.g. due to bad Reflux Drum level measurement or control valve sticking). Note, however, that liquid carryover due to foaming could also swing the reflux rate.

6	Work with Operations to ensure immediate stabilizing actions are taken	1. Symptoms are not addressed in a timely enough manner to prevent environmental exceedances or upsets to downstream units.	1A. Inject recommended dosage of antifoam. Do not exceed maximum dosages. To limit likelihood and consequences of over-dosing, it is ideal to inject only in front of the column that is experiencing foaming. Note antifoam tends to accumulate at the interface layer in LPG/Amine treaters where it may promote formation of emulsions due to its effect on lowering surface tension. Reference Antifoam Good Practice as needed: https://collab001-hou.sp.chevron.net/sites/gdMFSulfBIN/BINs/SRU_Amine/Wiki/Wiki%20Pages/Antifoam%20Good%20Practice.aspx 1B. Reduce throughput as needed to the affected tower. • Reducing vapor rate (Sour Gas feed to Absorber or Reboiler Steam to Regenerator) will generally be more effective than reducing liquid (amine) rate. However, cutting amine circulation likely has less economic penalty and may be enough to stabilize unit. Avoid extended operation above rich loading limits.
7	Develop list of applicable root causes to troubleshoot, prioritized by likelihood.	1. Resolution is delayed because a potential cause or solution may be missed, or time is spent preferentially on the causes which are of lower likelihood.	1A. If foaming verified, it is due to contamination of the amine beyond the ability of the normal control measures (filters, carbon, skimming, antifoam) to mitigate. Reference SRU/Amine BIN site for detailed description of foaming and it root causes: https://collab001-hou.sp.chevron.net/sites/gdMFSulfBIN/BINs/SRU_Amine/Wiki/Wiki%20Pages/Foaming.aspx 1B. Visually inspect amine solution to identify step changes in particulates, color, free oil, and haze in order to narrow down cause.

8	Verify adequacy of control measures	1. Carbon and particulate filters are quickly saturated when free oil is present, and are ineffective control measures until the bulk of the oil in the amine is removed. 2. Once contaminated, the amine system inventory may require significant time to clean-up. 3. Over-use of antifoam will saturate particulate and carbon filters.	1A. Skim excess hydrocarbons from unit at the Rich Amine Flash Drum and any other available locations, such as the Reflux Drum and Absorber and Regenerator Bottoms. 1B. Ensure slug catchers and coalescers upstream of Absorbers are functioning properly 2A. Ensure particulate filters are functional, anticipate/schedule change-outs to minimize time filters are bypassed. 2B. Ensure Carbon (if present) is not spent, change-out as needed. Typical carbon changeout frequency is 6 to 9 months for clean systems, but can be much shorter. 2C. Ensure Heat Stable Salt control program is effective. The presence of organic acids can increase the solubility of hydrocarbons (in the amine) which may promote foaming. 3. Inject antifoam at recommended dosage, bypassing filters and carbon treatment (if possible) for roughly 1 hour when injecting to keep antifoam from using up their capacity
9	Check if abnormal levels of contamination are occurring and address as needed.	1. Control measures may be ineffective if fresh contamination is still occurring.	1A. Ensure Lean Amine to Absorber is warm enough to not condense hydrocarbons out of Sour Gas feed, usually a 10-15 F margin between Lean Amine and Sour Gas temperature is needed. 1B. Verify unit is operated within guidelines for corrosion prevention to minimize iron sulfide particulate generation. 1C. Check for possible introduction of surfactants into the amine from unit clean-up activities (for instance, vapor phase cleaning to flare gas recovery is a possible route). 1D. Check operation of equipment upstream of Absorbers to identify signs of oil carryover into the amine, e.g. diesel carryover from Sponge Absorber. 1E. Verify antifoam addition has not been excessive.
10	Involve experts if issues remain unresolved	1. Issue will continue un-addressed	1. Contact Amine Treating and/or Distillation Subject Matter Experts and/or Amine vendor (e.g. Huntsman) for additional Technical Support.